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November 22, 2013

Via Email
Original via Mail

British Columbia Public Interest Advocacy Centre
Suite 209 – 1090 West Pender Street
Vancouver, B.C.
V6E 2N7

Attention: Ms. Tannis Braithwaite, Acting Executive Director

Dear Ms. Braithwaite:

Re: FortisBC Inc. (FBC)

Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 (the Application)

Response to the British Columbia Public Interest Advocacy Centre on behalf of the British Columbia Pensioners' and Seniors' Organization *et al* (BCPSO) Information Request (IR) No. 2

On July 5, 2013, FBC filed the Application as referenced above. In accordance with Commission Order G-165-13 setting out the Amended Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCPSO IR No. 2.

FBC notes that the response to BCPSO IR 2.21.1 relates to the PBR Methodology, and will be submitted with the PBR Methodology IRs on December 6, 2013, in accordance with the Regulatory Timetable.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Dennis Swanson

Attachments

cc: Commission Secretary
Registered Parties (email only)

1.0 Reference: Exhibit B-7, BCUC 1.21.1

1.1 Please re-do the response to BCUC 1.21.1, but isolating those elements of the Revenue Requirement that are not subject to flow-through and/or true up through variance accounts.

Response:

As requested, the above referenced Table has been redone below:

REVENUE DEFICIENCY		Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018	Average 2014-2018
"Adjusted" Revenue Requirements determined under the PBR Framework: (Adjusted Per BCPSO IR-2 Q1.1)							
O&M Expense		61,386	61,744	60,960	62,378	63,302	61,954
Capitalized Overhead		(12,277)	(12,349)	(12,192)	(12,476)	(12,660)	(12,391)
Income Taxes		(6,181)	(7,362)	(6,584)	(5,813)	(5,100)	(6,208)
Cost of Debt							
Cost of Equity		1,309	4,554	7,088	9,100	11,009	6,612
Depreciation and Amortization		-	4,068	7,536	9,869	12,298	6,754
Total	**A**	**44,236**	**50,655**	**56,808**	**63,059**	**68,848**	**56,721**
"Adjusted" Revenue Requirements not determined under the PBR Framework: (Adjusted Per BCPSO IR-2 Q1.1)							
Power Purchases							
Water Fees							
Wheeling		5,224	4,856	4,952	5,050	5,208	5,058
Other Income		(7,582)	(7,630)	(7,781)	(7,755)	(7,819)	(7,713)
Property Taxes							
Income Taxes							
Cost of Debt							
Cost of Equity		43,590	41,456	39,854	38,429	36,830	40,032
Depreciation and Amortization		57,773	51,999	50,681	50,688	50,579	52,344
Flow Through Adjustments							
Rate Smoothing		22,567	(2,430)	(10,112)	(7,100)	(2,925)	-
Total	**B**	**121,573**	**88,251**	**77,595**	**79,313**	**81,873**	**89,721**
Total "Adjusted" Revenue Requirements not determined under the PBR Framework after isolating those elements of the Revenue Requirement that are not subject to flow-through and/or true up through variance accounts:	**C=A+B**	**165,809**	**138,906**	**134,403**	**142,372**	**150,722**	**146,442**
Total Forecast Revenue Requiremnts ("Unadjusted") Per BCUC IR-1 Q21.1	**D**	**323,405**	**335,990**	**349,102**	**362,926**	**377,740**	**349,833**
"Adjusted" Revenue Requirement determined under the PBR framework as a % of Total "Unadjusted" Forecast Revenue Requirement:	**A/D**	**14%**	**15%**	**16%**	**17%**	**18%**	**16%**
"Adjusted" Revenue Requirement "NOT" determined under the PBR framework as a % of Total "Unadjusted" Forecast Revenue Requirement:	**C/D**	**51%**	**41%**	**38%**	**39%**	**40%**	**42%**

Note: The table has not been updated per the evidentiary update in order to allow comparability to the IR 1.21.1 response.

2.0 Reference: Exhibit B-7, BCUC 1.34.4

Exhibit B-1, Tab C, Table C5-2

2.1 Please explain what accounts for the difference between the $54.882 M in approved major capital project spending for 2013 and the actual spending of $67.584 M.

<u>Response:</u>

The primary difference between the $54.882 million in approved major capital project spending for 2013 and the actual spending of $67.584 million is explained as follows. The approved major capital project spending for 2013 includes two unapproved CPCN projects: the Kelowna Bulk Transformer Capacity Addition and the Kootenay Long Term Facility, for which there is zero 2013 capital spending. In addition, the PCB Environmental Compliance project has reduced spending due to scope rationalization resulting in a shift in project schedule. Further contributing to the PCB Environmental Compliance project shift in schedule is the 2013 labour dispute between FBC and IBEW employees. The Advanced Metering Infrastructure project has reduced spending due to the timing of the decision.

Offsetting the above reduced spending is the 2013 purchase of the City of Kelowna assets.

3.0 Reference: Exhibit B-7, BCUC 1.73.1 and 1.73.3

Preamble: Exhibit B-1, page 84 states that "the commercial class forecast is based on a regression of load on provincial GDP".

3.1 Please confirm that, to the extent historic growth has been reduced by DSM and/or year over year increases in electricity prices, this will impact on the regression equation estimated and, likely, the coefficient calculated for provincial GDP. If not confirmed, please explain why.

Response:

Confirmed. All historical savings, if any, were embedded in the commercial load data that were used in the regression to forecast the before-saving load and therefore impacted the regression coefficient.

3.2 Wouldn't using this regression equation (for commercial load) in conjunction with forecasts of increased provincial GDP implicitly incorporate higher levels of DSM in the resulting commercial load forecast and lead to double counting when combined with FortisBC's forecasts of incremental DSM savings? If not, please explain fully why not.

Response:

No, DSM impacts will not be double-counted. Impacts of DSM programs introduced before 2012 are embedded in the historical load, and therefore reflected in the before-savings load forecast, which does not take into account incremental DSM savings from programs introduced from 2013 on. Impacts of the incremental DSM savings were then subtracted from this load forecast, together with other incremental savings, to obtain the final after-savings load forecast.

3.3 Based on the response to BCUC 1.73.3.2, please indicate what FortisBC's average annual rate increase was over the period used to estimate the commercial class' regression equation.

Response:

The 2000-2012 period was used to estimate the commercial class regression equation. The average of annual rate increases over this period, as provided in the response to BCUC IR 1.73.3.2, is 4.3 percent. For convenience purposes, the rate increases in this period are provided below.

Annual Rate Change	Percent Increase (Reduction)	Order
January 1, 2000	5.1%	G-142-99
January 1, 2001	5.0%	G-130-00
January 1, 2002	4.5%	G-133-01
January 1, 2003	4.3%	G-10-03
January 1, 2004[1]	0.4%	G-38-04 & G-82-04
January 1, 2005	3.4%	G-52-05
January 1, 2006	5.9%	G-58-06
January 1, 2007[2]	2.8%	G-162-06 & G-20-07
January 1, 2008[3]	3.4%	G-147-07 & G-70-08
January 1, 2009[3]	5.3%	G-193-08
January 1, 2010[3]	7.1%	G-162-09 & G-127-10
January 1, 2011[3]	7.5%	G-184-10, G-195-10 & G-191-11
January 1, 2012	1.5%	G-110-12

Notes:

[1] The annual general rate increase occurred on May 1, 2004, however for comparison purposes the full year equivalent of the mid-year 2004 rate increase has been provided. As well, a mid-year rate decrease also occurred in 2004. The full year equivalent of the mid-year 2004 rate decrease has been added to the annual general rate increase.

[2] A mid-year rate increase occurred on April 2, 2007. The full year equivalent of the mid-year 2007 rate increase has been added to the annual rate increase that occurred on January 1, 2007.

[3] In each of the years of 2008 through 2011, FBC flowed through increased power purchase costs as a result BC Hydro rate increases mid-year. The full year equivalent of the mid-year rate increases has been added to the annual rate increase that occurred at the beginning of each year.

3.4 Wouldn't using this regression equation (for commercial load) already include some allowance for rate-driven savings? If not, please explain why.

Response:

Confirmed. The regression used historical loads with embedded savings, therefore it may already include some allowance for rate-driven savings.

3.5 Please provide a copy of the "Company's comparison study" as referenced in the response to BCUC 1.73.1.

Response:

The study was not a formal study, but an analysis exercise only of Appendix 5 of the 2012 BC Hydro's (BCH) load forecast document.

4.0 Reference: Exhibit B-7, BCUC 1.96.3

Exhibit B-1, Table C4-1

4.1 Table C4-1 shows lower than approved actual OM&A spending for both the EH&S and HR groups in 2012. Please explain why these savings were not sustained in 2013.

Response:

Savings were not sustained in EH&S in 2013 due to the filling of vacancies within the department that were delayed in 2012, in addition to reduced charge-out levels for staff as aligned with 2013 capital works where EH&S assistance had been required in previous years.

Savings were not sustained in the HR group in 2013 due to a number of factors, including:

- Initiatives undertaken in 2013, such as pension plan consulting and analysis and preparatory work related to various tables of collective bargaining;
- The timing of cross-charging for services performed in 2012, but not processed until 2013; and
- Regular increases to certain factors, such as inflation and the fringe benefits load.

FBC notes that the difference between O&M spending for the HR group between 2012 Actual and 2012 Approved is approximately 1.3%, and the difference between O&M spending for the HR group between 2013 Projection and 2012 Approved is approximately 1.8%.

5.0 Reference: Exhibit B-7, BCUC 1.98.4

5.1 Please confirm that by including the Generation and MRS adjustments in the 2013 Base OM&A, that these costs will be subject to annual adjustments for (I-X) and customer growth.

Response:

Confirmed.

5.2 Please explain why it is necessary for the annual budgets for these two items to be escalated by customer growth.

Response:

Please refer to the response to CEC IR 2.16.2.

6.0 Reference: Exhibit B-7, BCUC 1.136.7

6.1 Please indicate what "other costs have been absorbed in non-labour" in 2013 that account for the overall increase in non-labour costs and discuss whether these costs are one-time or ongoing expenses.

Response:

Other costs that have been absorbed in non-labour include travel costs, consulting costs (compensation, pension and benefit), as well as the cost of HR programs (including staff service recognition). Some of these expenses are ongoing, such as travel and HR programs. Others, such as consulting costs, are one-time expenses. These one-time consulting expenses occur with regularity and support continual validating and refinement of compensation (bargaining unit and M&E) and benefits and pension administration. Including consulting budget to support the completion of analysis is prudent, as FBC continues to evaluate the competitiveness of programs and look to achieve program efficiencies.

7.0 Reference: Exhibit B-7, BCUC 1.143.5 and 1.144.1

7.1 Given there is a Director, Internal Audit that manages the audit departments for both the Electric and Gas utilities, what additional oversight is provided/required from Fortis Inc.?

<u>Response:</u>

Oversight of all subsidiary internal audit activity is undertaken by Fortis Inc. Internal Audit. This includes monitoring audit activity, individual audit results, sharing of audit programs and key findings between the various Fortis subsidiaries, as well as reporting of consolidated audit findings to the Fortis Inc. Audit Committee for corporate oversight. Actual audit activities are carried out at the subsidiary level for both the Electric and Gas utilities.

8.0 Reference: Exhibit B-7, BCUC 1.144.6 and 1.144.7

8.1 Please clarify and confirm whether the proposed Base Corporate OM&A costs ($3.926 M) for FortisBC are based on Corporate costs determined by i) Executive time estimates or ii) the Massachusetts Formula.

Response:

The 2013 Base Corporate O&M Expense is based on several components and not all of the components are allocated based on either time estimates or Massachusetts Formula. The $3,926 thousand of Total 2013 Base Corporate O&M Expense is comprised of $1,725 thousand for Fortis Inc. Corporate Service fees, $246 thousand of Board of Directors O&M expense and $1,955 thousand of Executive Management team (Executive) O&M expense, as described in Section C4.17.1 on page 167 of FBC's 2014-2018 PBR Filing. This application describes how each of these Corporate O&M components are determined using different cost allocation methodologies.

First, as described in Section C4.17.3.1, on page 170 of FBC's 2014-2018 PBR Filing, the Fortis Inc. Corporate Service fees are [emphasis added]:"allocated to FBC using the assets by subsidiary driver which is a valid cost driver given the organizational structure of Fortis Inc. This allocation method was approved by the Commission in the 2012-2013 RRA Decision Order G-110-12. As mentioned above the Fortis Inc. cost pools and allocation methodology were reviewed by KPMG and found to be reasonable."

Second, as described in C4.17.3.2, on page 171 of FBC's 2014-2018 PBR Filing, the Board of Director fees cost allocation are described with the following [emphasis added]: "the Massachusetts Formula results in an approximately 23 percent allocation to FBC of the shared Board of Director and Committee costs for 2013. The Massachusetts Formula was approved by the Commission as the Board of Director pooled costs allocation method in the 2012-2013 RRA Decision Order G-110-12"

Third, the Labour component of 2013 Base Executive Management team (Executive) O&M expense in the amount of $1,722 thousand, shown in Table C4-36 on page 171 of the 2014-2018 PBR Filing has been determined based on 2013 Projection Labour which used the Time Estimate Methodology, as approved pursuant to BCUC Order G-110-12, and subsequently adjusted for pension and OPEB inflationary assumptions, as discussed further in the response to BCUC IR 2.25.5. The remaining Non-Labour component of $233 thousand is based on the combined FEI and FBC Executive estimated non-labour costs attributable only to FBC.

9.0 Reference: Exhibit B-7, BCUC 1.166.0

9.1 Does FortisBC have fault indicators on the underground equipment in its legacy (i.e. pre-City of Kelowna) service area? If not, why not?

Response:

Since 2006, all new installations for FBC service territory or the City of Kelowna have fault indicators on the underground equipment.

10.0 Reference: Exhibit B-7, BCUC 1.172.2

10.1 Are the annual variances between approved and actual interest expense primarily due to i) differences between the forecast and actual cost for new debt or ii) differences between the forecast and actual amount of new debt issued?

Response:

The variances between approved and actual interest expense for 2002 to 2012 referred to in the response to BCUC IR 1.172.2 are the result of differences between forecast and actual interest rates on both long-term debt and short-term debt, differences between forecast and actual financing fees described in Section D1.1.3 on page 235 of the 2014-2018 PBR Filing, differences between forecast and actual volume of both long-term and short-term debt and differences between forecast and actual timing of long-term debt issuances.

In each of the years' interest expense provided in the response to BCUC IR 1.172.2, the variance in interest expense could be weighted more or less to any of these factors. An assumption cannot be made that interest expense is only attributable to one factor, as it will differ year to year, hence the lack of controllability and the request for the interest expense variance deferral. Further, the weighting of uncontrollable external market factors that drove the historical amount of interest expense variances resulting from differences between forecast and actual for long-term and short-term interest rates, long-term debt volume and timing of long-term debt issuances may not be indicative of what could potentially drive interest expense variances for the term of the PBR.

11.0 Reference: Exhibit B-7, BCUC 1.174.2 and BCUC 1.74.5

11.1 Are the $240,000 one-time and $100,000 annual ongoing costs FortisBC's share of the total cost that would be incurred by FortisBC Utilities in becoming an SEC Issuer?

<u>Response:</u>

The forecasted $240 thousand one-time and forecasted $100 thousand annual ongoing costs that FBC would incur in becoming an SEC Issuer consist of both FBC's share of the total costs that would be incurred by the FortisBC Utilities and costs that are specifically attributable to FBC in becoming an SEC Issuer.

12.0 Reference: Exhibit B-7, BCUC 1.187.1 and 1.187.2

12.1 Please explain why the Insurance Expense Variance Account is meant to only capture variances between forecast and actual insurance premiums when a significant portion of the variance between forecast and actual expenses are due to insurance deductibles along with first and third party claims.

Response:

The primary reason FBC proposes to only capture the variance between Forecast and Actual Insurance Premiums in the Insurance Expense deferral account is to provide for consistent treatment between the Electric and Gas divisions. Insurance premiums are outside the control of FBC, being subject to conditions in the insurance market which can be volatile at times.

12.2 What is the level of insurance expense that is included in the Base O&M for purposes of the PBR plan (including Kelowna)? Please separate out insurance premiums from the balance of the expense included.

Response:

While insurance expense is initially included in 2013 Base O&M as part of Governance O&M, insurance expense is subsequently removed from 2013 Base O&M subject to the formulaic drivers, as shown on line 3 of Table B6-5: Forecast O&M Formula Results under Section B6.2.4.2 on page 53 of FBC's 2014-2018 PBR Filing (Exhibit B-1). Insurance expense (including Kelowna) of $1,588 thousand is then added to the Formulaic O&M along with other adjustments related to AMI and pension and OPEB expense, as shown on line 22 of Table B6-5, in determining the total O&M Under PBR.

The response to BCUC IR 1.143.2 described the components of insurance expense, including the insurance premiums, as follows [emphasis added]: "For 2013, projected expenses are insurance premiums of $1,422 thousand, appraisal fees of $60 thousand, and first and third party liability expenses of $106 thousand."

13.0 Reference: Exhibit B-7, BCUC 1.190.5

Exhibit B-1, page 263, lines 36-39

13.1 Please explain why FortisBC proposes to exclude from the Interest Expense Deferral Account "variances between forecast and actual interest expense driven by the differences on forecast and actual average short-term debt balances" whereas variances associated with the volume and timing of issuing long-term debt (as compared to forecast) will be included.

<u>Response:</u>

Please refer to the response to BCUC IR 2.60.1.

14.0 Reference: Exhibit B-7, BCUC 1.192.2

14.1 What is the amount included in the Base O&M for Annual Reviews?

<u>Response:</u>

FBC includes in Base O&M the internal labour costs for regulatory processes, but, as explained in the response to CEC IR 2.37.1, does not track these costs separately and is unable to estimate indirect costs for regulatory processes. Incremental costs of regulatory proceedings, as described on page 259 of the Application, are captured in a deferral account.

14.2 Will the incremental cost of the Annual Review for each year be calculated by comparing this value (adjusted annually by the PBR formula) with the actual cost of the Annual Review? If not, how will the incremental cost be determined?

<u>Response:</u>

FBC refers to the incremental cost of regulatory proceedings as costs for legal fees, expert witnesses and consultants, Commission and intervener funding costs, required public notifications, staff travel and other general expenses such as miscellaneous facilities, stationery and supplies, and incremental labour costs (for time which is not captured in regular O&M).

As noted in the preamble to the question, internal labour costs associated with the Annual Reviews is included in Base O&M and will be subject to the I-X adjustment.

15.0 Reference: Exhibit B-7, BCUC 1.180.1 and BCUC 1.196.1

15.1 Please comment on whether or not FortisBC's proposal for rate base treatment of the City of Kelowna Acquisition Legal and Regulatory Costs deferral account aligns with the BCUC's "key principles" behind the treatment of deferral accounts as set out in response to BCUC 1.180.1.

Response:

FBC has stated in its Application, and more specifically in its response to BCUC IR 1.180.1 that it disagrees with the principles set out in that decision. Because the principles are not valid in FBC's view, it has not applied them to its deferral account proposals. It should be noted, however, that the factors identified in the first of the principles (that is, "the benefits of rate smoothing, the length of time where there is direct value related to the item being amortized, and the increased costs that longer amortization periods impose on ratepayers due to the accumulation of financing charges") are considered by FBC when proposing an amortization period for a deferral account.

16.0 Reference: Exhibit B-7, 1.180.1

Exhibit B-1, pages 267-268

16.1 Please comment on whether or not FortisBC's proposal for financing in 2013 using the Company's WACC and rate base treatment effective January 1, 2014 of the accounts set out on pages 267-268 aligns with the BCUC's "key principles" behind the treatment of deferral accounts as set out in response to BCUC 1.180.1.

<u>Response:</u>

Please refer to the response to BCPSO IR 2.15.1.

17.0 Reference: Exhibit B-7, BCUC 1.232.2.1

17.1 Is the 15.9 years reported as the Program Total Effective Measure Life calculated as a simple average of the individual program values or is it based on some form of weighted average? If the later, what is the weighting based on?

<u>Response:</u>

It is the weighted average measure life based on planned expenditures over the 2014-18 PBR period.

18.0 Reference: Exhibit B-7, BCUC 1.242.2

FortisBC's Application for Stepped and Standby Rates for Transmission Customers, BCUC 1.12.1

18.1 Please demonstrate how the $92.23/MWh LRMC used in the Industrial Stepped Rate Application is equivalent to the proxy for LRMC of new clean energy resources of $111.96/MWh expressed in nominal (i.e. un-escalating) dollars used in the AMI and the mTRC.

Response:

Both the $92.23/MWh and the $111.96/MWh were calculated from the same 30 year BC New Resources Market Energy Curve provided in FBC's 2012 Long Term Resource Plan[1]. The difference is in the escalation. The $92.23/MWh LRMC used in the Industrial Stepped Rate Application is calculated in real 2011 dollars, and escalates annually at the rate of inflation (assumed to be 2 percent/year). The $111.96/MWh LRMC used in the AMI and mTRC is calculated in nominal dollars, and does not escalate annually.

[1] FBC's 2012 Long Term Resource Plan, Appendix B: 2011 FortisBC Energy & Capacity Market Assessment, Table 5.2-A, Page 28 of 54.

19.0 Reference: Exhibit B-7, BCUC 1.242.2 and 1.244.1

19.1 Over what time frame is the nominal (i.e. un-escalating) $111.96/MWh value for LRMC referenced in BCUC 1.242.2 determined?

Response:

A 30-year time frame was used, commencing 2011.

19.2 Over what period were the nominal LRMC values shown in the response to BCUC 1.244.1 determined?

Response:

For BCUC IR 1.244.1: a 30-year time frame was used, commencing 2011.

For BCUC IR 1.244.2: a 30 year term commencing in 2014.

For BCUC IR 1.244.3: a 15 year term (as specified in the question), commencing in 2014.

19.3 BCUC 1.244.1 requested that the LRMC used in each scenario be based on the average levelized LRMC over the 5 year PBR period. Please explain why this value is also $111.96/MWh similar to that reported in BCUC 1.242.2.

Response:

The LRMC of New Resources of $111.96/MWh is calculated as a nominal dollar, un-escalating price.

Therefore the $111.96/MWh is the appropriate number to use for each year of the PBR period.

20.0 Reference: Exhibit B-7, BCUC 1.248.7

20.1 Please confirm that the Benefit/Cost ratios were calculated using a LRMC value of $56.61/MWh. If not, what value was used for LRMC and why?

Response:

Confirmed.

20.2 On what basis are the Average TRC Levelized Costs for the various programs calculated (i.e. is it a real or nominal value) and is this the same as the basis on which the $56.61 LRMC referenced in the response is determined/expressed?

Response:

The average TRC Levelized costs are calculated on a real value basis and are escalated to the present. The $56.61 LRMC is calculated on a nominal dollar basis, and does not escalate annually. It is equivalent to $45.33 calculated on a real basis in 2013 dollars, escalating annually at an assumed 2.1 percent.

20.3 Please explain how Clothes Washers can have a favourable Benefit/Cost ratio (i.e. 5.66) when its TRC levelized cost exceeds $56.61/MWh.

Response:

Despite its label, the levelized TRC measure costs calculated for the 2013 CDPR Update do not include non-energy costs or benefits; however, the benefit-cost ratios (the mandated cost-effectiveness screening tool) do include non-energy benefits.

In the case of clothes washers, there are significant quantifiable non-energy benefits including water savings (primarily) and some amount of detergent savings. The present value of these non-energy benefits is added to the present value of the electricity savings and therefore the benefit-cost ratio exceeds 1.0, even though the levelized cost exceeds the avoided cost. Had the 2013 CDPR calculated TRC *Net* Levelized Cost that included non-energy benefits and costs, then the TRC levelized cost of clothes washers would not exceed the levelized avoided cost of energy.

21.0 Reference: Exhibit B-10, CEC 1.2.2

21.1 Please explain what is meant by "uneconomic for the Company because payback cannot be achieved before rebasing". Under cost of service regulation, doesn't FortisBC pursue all cost-effective efficiency opportunities (i.e. opportunities where spending dollars derived from customers leads to lower costs for customers over the long term)?

Response:

This IR has been identified as relating to the PBR Methodology and will be submitted with the PBR Methodology IR responses.

22.0 Reference: Exhibit B-11, BCPSO 1.4.3 and BCPSO 1.5.1

22.1 Please confirm that any (capital) investments in IT systems and other initiatives (as referenced in BCPSO 1.4.3) will also be funded within the overall capital expenditure funding provided by the PBR formula? If not, what anticipated projects would not be covered?

Response:

Confirmed. Presently, FBC has not identified any potential investments in IT systems or other initiatives for which it would seek approval outside of the proposed PBR formula.

23.0 Reference: Exhibit B-11, BCPSO 1.6.1

23.1 Have FBC's customer satisfaction surveys provided any insight into whether or not customers consider the levels of service noted in the response for Emergency Response, Telephone Service, Meter Reading Accuracy or reliability as being at a "high level"?

Response:

FBC is of the opinion that research scores show a high level of satisfaction with service quality across each area. This claim is supported by results from FBC's Customer Satisfaction Index (CSI) and Service Quality Measurement survey (SQM).

The CSI measures residential and small commercial customer satisfaction with various aspects of FBC's electric service including: satisfaction with the contact centre, satisfaction with meter reading accuracy, and satisfaction with service reliability. The table below highlights the customer satisfaction scores for those service aspects for the last four quarters. The scores are measured on a ten point scale where 1 is "Not at all satisfied" and 10 is "Extremely satisfied."

Customer Satisfaction Levels

	Q4 2012	Q1 2013	Q2 2013	Q3 2013
Overall Satisfaction with the Contact Centre	8.3	8.1	7.8	8.4
Satisfaction with the Accuracy of Meter Reading	8.3	7.9	7.8	7.8
Reliability of electrical supply	8.3	8.3	8.3	8.3

The FBC CSI does not evaluate emergency calls. There are a limited number of emergency calls received monthly so survey results would be statistically unreliable. However, the Service Quality Measurement (SQM) survey, which has measured contact centre performance by call type since April 2013, indicates that year to date, 81 percent of customers are satisfied with their experience in relation to emergency/outage type calls.

The results support FBC's assertion that customers rate service highly.

24.0 Reference: Exhibit B-11, BCPSO 1.65.2 and 1.65.4

Exhibit B-11, BCPSO 1.66.1 and 1.66.2

24.1 How does FortisBC ensure that input received from its industrial customer and wholesale customer load surveys do not include the impact of future rate-driven savings?

Response:

The Company did not specifically ask the industrial and wholesale customers for their estimate of future rate-driven savings, nor would industrial customers have the knowledge or background in regulatory forecasting to provide such an estimate. Industrial customers estimate their energy based upon, but not limited to, their knowledge of their business, the economic conditions, the cost of electricity, costs of competing fuels, etc. FBC believes that the industrial customer is the one best able to forecast their consumption based upon their business knowledge. There is not a need to introduce regulatory forecasting constructs to the customer's own estimates of future consumption.

25.0 Reference: Exhibit B-11, BCPSO 1.72.2

25.1 Please reconcile the Total O&M values by year in this response with those set out at the bottom of Figure B6-2 of the Main Application.

Response:

The numbers below are different because the departmental O&M budget view had a late minor adjustment which inadvertently was not updated on Figure B6-2.

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Department View O&M - BCPSO IR1 Q 1.72.2	61,382	61,592	60,619	61,899	62,641
Main Application - Figure B6-2 O&M Forecast	61,375	61,612	60,608	61,889	62,634
Difference	**7**	**(20)**	**11**	**10**	**7**

25.2 Are there specific O&M costs included in the high level forecast of future O&M costs and that are not meant to be captured by the PBR formula?

Response:

No. Other than the adjustments included in the Application Table B6-5 the only O&M costs that are to be tracked outside of the formulaic O&M are Pension/OPEB, Insurance and AMI costs/benefits.

25.3 If yes, what are they and what are the currently forecast annual values for 2014-2018?

Response:

Please refer to the response to BCPSO IR 2.25.2.

25.4 If no, please confirm that based on current assumptions regarding the future inputs to the PBR formula, the O&M forecast based on the PBR formula is higher than the high level trend O&M forecast in each year of the PBR period.

Response:

Confirmed, however as shown in the Application Figure B6-2 on page 54, the PBR formulaic O&M amount closely aligns with the high level O&M trend, and based on the level of accuracy possible the Company considers them essentially the same. Further as stated in the Application on page 54:

> *"…the O&M expense allowed under the PBR formula closely aligns with the forecast O&M throughout the PBR term, particularly in the early years of the PBR period. Considering the material efficiencies of 10.4 percent embedded in FBC's O&M expense by way of productivity improvement factors during its last PBR period from 2007 to 2011, and in particular the extent to which the proposed X factor exceeds the measured industry productivity levels, FBC believes this level of O&M expenditure allowed under PBR provides a strong incentive to continue to find efficiencies for O&M spending."*

26.0 Reference: Exhibit B-12, BCSEA 1.10.3.3.19

FortisBC's Stepped Transmission Rate Application,

Exhibit B-1, page 23 and Exhibit B-4, BCUC 1.5.10

26.1 Please explain why for the Stepped Transmission Rate Application FortisBC claims that the cost of developing generation from clean resources is the appropriate value for long-run marginal cost of power whereas for purposes of the evaluating DSM (using the TRC) FortisBC asserts that the long-run marginal cost of market purchases is the appropriate long run cost of marginal supply.

Response:

As FBC discussed in the Stepped Transmission Rate Application proceeding, Exhibit B-4, FBC response to BCUC IR 1.4.2 (reproduced below), the conservation pricing signal should reflect the avoided costs to the utility of the saved energy requirements due to conservation. However, given that the avoided cost associated with any saved energy (i.e. the LRMC of market purchases) is currently priced below the retail price of the energy, such a rate design could not result in an inclining block rate. In fact, a cost causation based rate that would ensure revenue neutrality (by class), would likely resemble a declining block rate because the marginal cost of power is currently lower than the average retail price of power. This situation is forecast to remain for quite some time. As the BCUC had directed FBC to create an inclining block rate structure for its industrial customers, another measure for the Tier 2 conservation rate needed to be utilized.

FBC believes that $0.09223/kWh ($92.23/MWh) used for Tier 2 industrial rates represents a good conservation price signal for its industrial customers. Rather than taking this to a theoretical level of specification which cannot be justified, FBC chose to use the LRMC cost of new generation resources developed in its 2012 Resource Plan, expressed in real 2011 dollars, as its Tier 2 price signal for industrial transmission customers.

The market forecast based LRMC used to value benefits in the DSM Plan is appropriately representative of the Company's avoided power purchases, on the wholesale market. This is in contrast to fulfilling the requirement to create a higher second-tier *retail* price for the industrial class.

4.0 Reference: RS 34 Stepped Rate – Bonbright Evaluation

James C. Bonbright, Principles of Public Utility Rates, Columbia University Press

The Commission 2009 Report to the Government on the BC Hydro TSR Program

Exhibit B-1, p. 18

Principal 2

Principle 2: Fair apportionment of costs among customers (appropriate cost recovery should be reflected in rates)

The Commission 2009 Report to the Government on the BC Hydro Transmission Service Rate Program states on page 8:[2]

"Costs have shifted from the TSR customer class to other customer classes and the shareholder."

4.2 Does FortisBC consider that principles of revenue neutrality will reduce the conservation signals? Please explain why or why not.

<u>Response:</u>

The load forecast that the Company uses in its revenue requirements will incorporate some assumption about the amount of conservation that results from the implementation of a conservation rate. Therefore, if the expected conservation is realized, the rate will be revenue neutral on a forecast basis. It will not, however, be revenue neutral to the flat rate that would otherwise exist.

The important consideration is really that in the current cost environment any conservation, whether prompted by a rate or DSM, will have the effect of increasing customers' rates due to the resulting lost revenue.

The solution to this dilemma is to ensure that rates charged for conservation consider the marginal cost of power. The conservation pricing signal should reflect the avoided costs to the utility of the avoided energy requirements due to conservation. However, given that the avoided cost associated with any saved energy is currently priced below the retail price of the energy; such a rate design could not result in an inclining block rate. In fact, a cost causation based rate that would ensure revenue neutrality (by class), would likely resemble a declining block rate because the marginal cost of power is currently lower than the average retail price of power. This situation is forecast to remain for quite some time.

[2] http://www.bcuc.com/Documents/Reports/BCUC-TSR-Evaluation-Report-December_31_2009.pdf

27.0 Reference: October 18, 2013 Evidentiary Update, page 57

27.1 Please indicate specifically what projects/expenditures were deferred as a result of i) the delayed approval in August 2012 versus ii) the 2013 labour dispute between FBC and its IBEW employees.

Response:

The projects initially deferred to 2013 as a result of the delayed August 2012 approval, that continue to be deferred to 2014/15 due to the ongoing 2013 labour dispute, are primarily as follows: All Plants Concrete and Structural Rehabilitation; Ellison to Sexsmith Transmission Tie; 6 Line/26 Line River Crossing Reconfiguration; 21-24 Lines Rebuild (Generation Plants); and 41 Line Salvage and Distribution Underbuild Rehabilitation.

With respect to the impact of the ongoing 2013 labour dispute, the majority of all capital projects were placed on hold on June 26, 2013

27.2 Given the original application was filed in July 2013 please explain why the deferrals caused by the delayed approval in August 2012 were not known at the time it was prepared/filed.

Response:

The 2012 projects deferred into 2013 as a result of the delayed approval were known when the application was filed in July 2013. The statement from page 57 of the Evidentiary Update was intended to describe the further deferral of expenditures (due to the labour dispute) already previously deferred from 2012 due to the delayed 2012/13 RRA approval.

The deferral of capital projects into 2014 does not impact the capital expenditure formula for the PBR Plan because FBC used the approved capital expenditures for 2013 from the 2012-2013 RRA Decision as the starting point for the capital formula, recognizing that the 2013 Capital Base should be based upon the 2013 approved capital (a value that has undergone a full review through an oral public hearing).

27.3 Please confirm that this deferral will reduce the forecast rate base for 2013 and 2014 as compared to that presented in the original application.

Response:

It is confirmed that the above referred Capital deferral will reduce the forecast rate base for 2013 and 2014 as compared to that presented in the July 5, 2013 Application.

28.0 Reference: October 18, 2013 Evidentiary Update, pages 58 and 179

28.1 Please explain why the total 2013 deferred capital spending in 2014 and 2015 (per page 58) is less than the amount deferred from 2013 as shown on page 179.

Response:

The total $37.539 million deferred capital spending in 2014 and 2015 (per page 58) is the carry-over spending, due to the labour dispute between FBC and the IBEW.

The $38.825 million (per page 179) is the total reduction in the 2013 forecast, when compared to the July 5th filing. This value includes the 2014 and 2015 carry-over spending, as well as reductions in projects forecasts (primarily in New Connects System Wide, Distribution Forced Upgrades, and Meter Changes) excluded from the total 2014/15 carry-over.

29.0 Reference: October 18, 2013 Evidentiary Update, Cover Letter, page 4 and updated page 249

29.1 Please provide a schedule that breaks down the $9.1 M increase attributable to Financing as between i) Cost of Debt, ii) Cost of Equity, iii) Depreciation (related to fixed assets) and iv) Amortization (related to regulatory accounts) by year.

Response:

The requested schedule has been provided below:

Financing Cost (Incremental)	2014	2015	2016	2017	2018	Total
	($000s)					
Cost of Debt	(153)	1,092	1,915	2,086	2,019	**6,958**
Cost of Equity	(1,283)	(472)	218	211	180	**(1,146)**
Depreciation (Fixed Assets)	(1,121)	(677)	338	170	2	**(1,288)**
Amortization (Regulatory Accounts)	517	188	1,382	1,143	1,373	**4,604**
Total Incremantal Financing Cost:	**(2,040)**	**130**	**3,854**	**3,610**	**3,574**	**9,127**

29.2 Please separate out the impact on annual depreciation expense of i) the change in depreciation rates noted on page 249 versus ii) the impact of the deferred capital spending.

Response:

Please refer to the response to BCUC IR 2.49.2.2.

30.0 Reference: October 18, 2013 Evidentiary Update, pages 266 and 287

30.1 Please confirm that the current update does not include any provision for City of Kelowna Acquisition Phase 2 costs.

Response:

The update includes $500 thousand and $125 thousand (before tax) for the CoK Acquisition Phase 1 and Phase 2 costs, respectively.

30.2 What is FortisBC's current estimate as to what the Phase 2 costs will be?

Response:

Please refer to the response to BCPSO IR 2.30.1.

31.0 Reference: October 18, 2013 Evidentiary Update, Appendix E, page 3

31.1 Please confirm that the only changes were with respect to the Provincial Income Tax rate and the Weighted Average Cost of Debt.

Response:

Not confirmed. While Schedule 3 Income Tax was updated to reflect the change in the Corporate Tax Rate and updated interest rates and updated debt volumes, as opposed to specifically the Weighted Average Cost of Debt, there were other updates reflecting the filing of the 2012 T2 corporate tax return and the relevant revenue requirement changes that resulted from shifting a certain amount of capital expenditures from 2013 to 2014.

An overview of these changes was documented on page 4 of the cover letter which accompanied the Evidentiary Update filing on October 18, 2013 as follows:

> *"As a result of filing the corporate income tax return, 2013 projected income taxes have been updated for changes in the opening Undepreciated Capital Cost (UCC) balances and prior year's overprovision. 2014 through 2018 forecast income taxes have also been updated to reflect the change in opening 2013 UCC balances.*
>
> *Income tax for 2013 projected and 2014 through 2018 forecast have been updated to reflect the effect of the capital expenditure carry over from 2013 to future years (discussed below), including the impact on capital cost allowance and the other items identified within this letter which affect the calculation of income taxes."*

32.0 Reference: October 18, 2013 Evidentiary Update, Appendix G, page 1

32.1 Please provide a revised Schedule that includes 2013.

Response:

REVENUE REQUIREMENTS OVERVIEW

		Projected 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
1	Sales Volume (GWh)	3,189	3,240	3,258	3,276	3,295	3,318
2	Rate Base	1,140,542	1,191,683	1,244,204	1,288,533	1,304,375	1,311,983
3	Return on Rate Base	7.59%	7.22%	7.10%	7.14%	7.16%	7.16%
4					($000s)		
5	**REVENUE DEFICIENCY**						
6							
7	**POWER SUPPLY**						
8	Power Purchases	83,479	87,163	115,590	134,063	136,938	140,550
9	Water Fees	9,387	9,928	10,532	10,479	10,688	10,902
10		92,866	97,091	126,122	144,541	147,626	151,452
11	**OPERATING**						
12	O&M Expense	57,169	61,386	61,744	60,960	62,378	63,302
13	Capitalized Overhead	(11,524)	(12,277)	(12,349)	(12,192)	(12,476)	(12,660)
14	Wheeling	5,209	5,224	4,856	4,952	5,050	5,208
15	Other Income	(7,947)	(7,582)	(7,630)	(7,781)	(7,755)	(7,819)
16		42,907	46,751	46,621	45,939	47,198	48,030
17	**TAXES**						
18	Property Taxes	14,867	15,903	16,329	16,612	16,975	17,290
19	Income Taxes	11,141	10,815	5,379	3,710	7,079	10,287
20		26,008	26,718	21,708	20,322	24,054	27,577
21	**FINANCING**						
22	Cost of Debt	39,171	42,454	42,833	44,840	45,631	45,880
23	Cost of Equity	47,418	43,616	45,538	47,160	47,740	48,019
24	Depreciation and Amortization	49,781	57,169	55,578	59,938	61,870	64,253
25		136,370	143,239	143,949	151,938	155,241	158,151
26							
28	Flow Through Adjustments	6,724	(14,772)	-	-	-	-
29	Rate Stabilization	-	24,375	(1,502)	(11,679)	(8,067)	(3,127)
30		6,724	9,603	(1,502)	(11,679)	(8,067)	(3,127)
31							
32	**TOTAL REVENUE REQUIREMENT**	304,875	323,403	336,898	351,061	366,051	382,083
33							
34	ADJUSTED REVENUE REQUIREMENT		323,403	336,898	351,061	366,051	382,083
34	**LESS: REVENUE AT APPROVED RATES**		312,924	325,108	338,710	353,165	368,650
35	**REVENUE DEFICIENCY FOR RATE SETTING**		10,479	11,790	12,351	12,886	13,434
36							
37	**RATE INCREASE**		**3.30%**	**3.60%**	**3.60%**	**3.60%**	**3.60%**

32.2 For each year 2013-2018, please explain the factors (and the $ contribution of each) to the change in rate base from that in original application.

Response:

The requested Table has been provided below:

SCHEDULE 1
UTILITY RATE BASE

		Evidentiary Update Filing RRA 2014 (18th October 2013)						First Fiiling RRA 2014 (5th July 2013)						Variance						Remarks (Primary changes)
		Forecast 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018	Forecast 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018	Forecast 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018	
																				Plants in Service:
																				2013: Capital shift from 2013 to 2014 & 2015
1	Plant in Service, January 1	1,589,905	1,678,589	1,784,714	1,874,702	1,935,087	1,996,023	1,589,905	1,718,111	1,804,278	1,873,922	1,934,325	1,995,295	-	(39,523)	(19,564)	780	761	729	2014: Increased Capital, Reduced Meter Retirements (AMI Decision), Offset by AMI shift
2	Net Additions	88,684	106,125	89,988	60,385	60,936	58,091	128,207	86,167	69,644	60,403	60,969	58,097	(39,523)	19,958	20,345	(19)	(33)	(6)	2015: Increased Capital and AMI Capital offset by Meter Retirements (AMI Decision)
3	Plant in Service, December 31	1,678,589	1,784,714	1,874,702	1,935,087	1,996,023	2,054,114	1,718,111	1,804,278	1,873,922	1,934,325	1,995,295	2,053,392	(39,523)	(19,564)	780	761	729	722	
4																				
5	Add:																			
6	CWIP not subject to AFUDC	10,825	7,534	7,402	7,405	7,589	7,678	6,784	7,678	8,384	8,536	7,304	7,390	4,041	(144)	(981)	(1,132)	285	288	2013: CWIP not subject AFUDC Increased from approximately $7M to $11M
7	Plant Acquisition Adjustment	11,912	11,912	11,912	11,912	11,912	11,912	11,912	11,912	11,912	11,912	11,912	11,912	-	-	-	-	-	-	
8	Deferred and Preliminary Charges	20,995	(4,462)	2,939	13,575	18,927	18,372	21,732	(2,530)	(454)	10,047	15,868	16,602	(737)	(1,932)	3,392	3,528	3,059	1,771	2013: Primarily DSM Reduction, 2014: Rate Smoothing Deferral, 2015-18: Accounting
9																				treatment of AMI Meters & Rate Smoothing
10		1,722,321	1,799,699	1,896,955	1,967,978	2,034,452	2,092,076	1,758,539	1,821,339	1,893,764	1,964,821	2,030,379	2,089,295	(36,218)	(21,640)	3,191	3,157	4,073	2,780	
11	Less:																			
12	Accumulated Depreciation																			
13	and Amortization	434,227	472,145	508,113	557,062	608,064	660,828	429,731	467,919	509,998	558,319	608,697	660,838	4,495	4,227	(1,885)	(1,257)	(633)	(10)	Variations in Cost of Removals, Depreciation (Capital) & AMI Retirements
14	Contributions in Aid of Construction	99,019	101,537	104,454	107,550	110,632	113,615	99,416	102,414	105,538	108,608	111,664	114,620	(397)	(877)	(1,083)	(1,057)	(1,031)	(1,004)	CIAC Reduced in 2013
15		533,245	573,683	612,568	664,613	718,697	774,444	529,147	570,333	615,536	666,927	720,361	775,458	4,098	3,350	(2,968)	(2,314)	(1,664)	(1,014)	
16																				
17	Depreciated Rate Base	1,189,076	1,226,016	1,284,388	1,303,366	1,315,755	1,317,632	1,229,392	1,251,006	1,278,228	1,297,894	1,310,018	1,313,837	(40,316)	(24,990)	6,159	5,472	5,737	3,795	
18																				
19	Prior Year Depreciated Rate Base	1,135,510	1,189,076	1,226,016	1,284,388	1,303,366	1,315,755	1,135,510	1,229,392	1,251,006	1,278,228	1,297,894	1,310,018	-	(40,316)	(24,990)	6,159	5,472	5,737	
20																				
21	Mean Depreciated Utility Rate Base	1,162,293	1,207,546	1,255,202	1,293,877	1,309,561	1,316,694	1,182,451	1,240,199	1,264,617	1,288,061	1,303,956	1,311,928	(20,158)	(32,653)	(9,415)	5,816	5,605	4,766	
22	Add:																			
23	Allowance for Working Capital	1,370	2,307	2,538	2,545	2,755	2,852	1,232	2,184	2,399	2,400	2,606	2,702	138	123	139	145	149	150	
24	Deferred Balance Adjust.	(6)	(4,630)	199	-	-	-	(6)	(3,801)	201	-	-	-	-	(829)	(2)	-	-	-	
25	Kettle Valley Adjustments	(25,756)	-					(25,756)	-					-	-	-	-	-	-	
26	Adjustment for Capital Additions	2,641	(13,540)	(13,735)	(7,889)	(7,941)	(7,563)	(11,259)	(11,845)	(10,110)	(7,891)	(7,945)	(7,564)	13,900	(1,695)	(3,625)	2	4	1	Capital movement from 2013 to 2014 & 2015
27																				
28	**Mid-Year Utility Rate Base**	**1,140,542**	**1,191,683**	**1,244,204**	**1,288,533**	**1,304,375**	**1,311,983**	**1,146,662**	**1,226,737**	**1,257,107**	**1,282,570**	**1,298,617**	**1,307,066**	**(6,120)**	**(35,054)**	**(12,904)**	**5,963**	**5,758**	**4,917**	

33.0 Reference: October 18, 2013 Evidentiary Update, Cover Letter, page 3

33.1 Please update the calculation of the levelized market price (per Appendix H4) based on the revised market price forecast referenced in the Evidentiary Update.

<u>Response:</u>

The June 15, 2013 Memo from Midgard Consulting provided the BC market price forecast in Appendix H4 is the most recent market price forecast.

34.0 Reference: Exhibit B-11, BCPSO 1.87.1

34.1 Please provide an analysis of costs that FBC has incurred and claimed related to each of the framework set out in *Canderel Ltd. v. Canada*, 1998 CarswellNat 81 (Supreme Court of Canada) and the Rainbow Pipe Line Co. v. R., 2002 CarswellNat 1378 (Federal Court of Appeal) decisions for 2008, 2009, 2010, 2011, and 2012 actual results. In the response, please include a cross reference to where the costs are included in actual costs in this Application.

Response:

FBC does not track its costs incurred and claimed as deductions in computing its income for tax purposes with specific reference to the framework set out in *Canderel Ltd. v. Canada, 1998 CarswellNat 81 (Supreme Court of Canada)* ("Canderel") and *Rainbow Pipe Line Co. v. R., 2002 CarswellNat 1378 (Federal Court of Appeal)* ("Rainbow"). The starting point in computing FBC's taxable income is its net income for book purposes. FBC then makes those adjustments necessary and appropriate to adjust its book income to arrive at its income for tax purposes. For the vast majority of transactions and expenditures, the categorization of expenditures for book purposes aligns with the treatment for income tax purposes as set out in Canderel and Rainbow and no adjustment to book income is necessary to determine income for tax purposes. Where adjustments to book income are necessary to compute income for tax purposes, FBC has made these adjustments in computing the tax expense used for rate setting purposes.

One such example that falls within the framework of *Canderel Ltd. v. Canada*, 1998 CarswellNat 81 (Supreme Court of Canada) and the Rainbow Pipe Line Co. v. R., 2002 CarswellNat 1378 (Federal Court of Appeal) is certain qualifying dismantling costs, also referred to as costs of removal. As thoroughly explained on pages 12-13 of Tab 3 of FBC's 2011 Revenue Requirements Application, dated October 1, 2010, and Section 4.6.2.3 Determination of Taxable Income on pages 111-112 of FBC's 2012-2013 RRA filed on June 30, 2011, certain qualifying costs of removal have been deducted for tax purposes and FBC's customers have benefited from these deductions in determining revenue requirements for 2011 and onwards, including the 2014-2018 PBR. For this specific example of costs eligible within the framework referred to in the question, these actual costs of removal eligible for deduction were included in "All Other" deduction line item included as part of Financial Schedule 3 – Income Taxes of the FBC's 2011 RRA and 2012-13 RRA and have been forecasted in the same "All Other" line item as part of Financial Schedule 3 – Income Taxes of the FBC's 2014-2018 PBR Filing.

34.2 Please provide the forecast costs and deductions related to each of *Canderel Ltd. v. Canada*, 1998 CarswellNat 81 (Supreme Court of Canada) and the Rainbow Pipe Line Co. v. R., 2002 CarswellNat 1378 (Federal Court of Appeal) decisions forecast for 2013, 2014, 2015, 2016, 2017, and 2018. In the response, please include a cross reference to where the costs are included in actual costs in this Application.

Response:

Please refer to the response to BCPSO IR 2.34.1.

For the years 2013 through 2018, FBC's forecast calculation of taxable income and details of the Timing Differences are shown in its Evidentiary Update from October 18, 2013 as indicated below:

Year	Document Reference
2013	Section E - Schedule 3
2014	Section E - Schedule 3
2015	Appendix G - Schedule 3
2016	Appendix G - Schedule 3
2017	Appendix G - Schedule 3
2018	Appendix G - Schedule 3

35.0 Reference: Exhibit B-11, BCPSO 1.90.1

35.1 In BCPSO 1.90.1, FBC states "Starting in 2014 the Executive cross charges to and from FEI are expected to use the Massachusetts Formula during the term of the PBR, instead of management estimates of time allocations as used in the recent past." Please provide an analysis that quantifies the allocations of Executive cross charges under the historic method and under the Massachusetts method for 2008, 2009, 2010, 2011, and 2012 actual results.

Response:

Please refer to the response to BCUC IR 2.25.2.

35.2 Please provide the forecast allocated costs for Executive cross charges for 2014, 2015, 2016, 2017, and 2018. In the response, please fully explain how the change to the Massachusetts formula has been incorporated into the forecasts.

Response:

Please refer to the response to BCUC IR 2.25.5.

36.0 Reference: Exhibit B-11, BCPSO 1.90.4.2

36.1 In the response to BCPSO 1.90.4.2, FBC discusses why the Massachusetts formula for the allocation of Fortis Inc. Costs. Please provide FBC's understanding of other allocation formulae that may exclude the cost of energy from the allocation formula, such as the Distrigas formula.

Response:

FBC and FEI are aware of other allocator models, such as Kansas, ATCO and similar types of allocators, however they are less relevant for allocating Fortis Inc. costs. The Commission has previously approved revenue requirement applications which included the allocation of Fortis Inc. costs to its subsidiaries based on the Asset Allocation methodology. The appropriateness of applying the Asset Allocation methodology to allocate Fortis Inc. costs over the other alternatives was further supported through external reviews in 2009 and 2013 by third party consultant KMPG.

The response to BCPSO IR 1.90.4.2 discussed why the Fortis Inc. costs should not be allocated using the Massachusetts formula due to the lack of relationship with revenue and payroll, as well as the merits around the use of the Asset allocation method which has been approved by the BCUC for allocating Fortis Inc. costs. That response included the price of energy in the revenue calculation, however FBC is of the view that it is appropriate to use operating margin which excludes the cost of energy, rather than gross revenues when applying the formula. When FHI, FEI and FBC refer to the historically approved and proposed allocation of costs within the FortisBC Utilities using the Massachusetts Formula, it excludes the price of energy from revenue.

Even when considering the Massachusetts Formula excluding the cost of energy (as shown in the response to BCPSO IR 2.37.1), it is still not appropriate to use in allocating Fortis Inc. costs as the nature of one of the three main factors, payroll, is not considered as a reasonable driver of the relationship.

36.2 Please fully explain why the cost of energy should be included in the allocation of Fortis Inc. Costs.

Response:

As outlined in the response to BCPSO IR 2.36.1, the Fortis Inc. costs are allocated using the Asset allocation method rather than the Massachusetts formula.

The responses to BCPSO IR 1.90.4.2 and BCPSO IR 2.37.1 involve modelling hypothetical scenarios that contemplate allocating Fortis Inc. costs using the traditional Massachusetts formula, which includes the cost of energy, and the modified Massachusetts formula, which excludes the cost of energy.

When FHI, FEI and FBC refer to the historically approved and proposed allocation of costs within the FortisBC Utilities using the Massachusetts Formula, it is actually using a modified version of the Massachusetts Formula that excludes the price of energy from revenue. For example, the allocation of costs from FHI to the FEU used the modified version of the Massachusetts Formula that excludes the cost of energy. In this instance, the costs which are allocated from Fortis Inc. are then added together with the services from FHI and are allocated to the FEU via the modified Massachusetts formula. In this case, the net margin (revenue less cost of energy) is used as an input into the Massachusetts formula, meaning that the cost of energy is **excluded** from the allocation of these costs.

37.0 Reference: Exhibit B-11, BCPSO 1.90.4.3

37.1 In the response, FBR provides an analysis that compares the Massachusetts formula to the current asset allocation model. In the request, the BCPSO requested that the price of energy (natural gas or electricity) be removed from the revenue used in the formula. Please confirm that the tables provided in response to BCPSO 1.90.4.3 have removed the impact of the price of energy (natural gas or electricity) be removed from the revenue used in the formula. If not confirmed, please provide a revised response that eliminates the price of energy from the revenue used in the Massachusetts formula.

<u>Response:</u>

As described in the response to BCPSO IR 2.36.1, the table provided in the response to BCPSO 1.90.4.3 was based on a scenario that included the price of energy in the revenue calculation. Therefore, as requested, the following table is based on the response to BCPSO 1.90.4.3 and has been revised to eliminate the price of energy from revenue for applying the Massachusetts formula.

<u>Massachusetts Formula Model revised (using operating margin) for BCPSO IR2.37.1</u>

	Actual			*Estimate*
	2010	**2011**	**2012**	**2013**
	(000s)			
Net operating costs recoverable	$ 10,015	$ 12,239	$ 12,953	$ 12,575
FBC rate using Massachusetts Formula	13.29%	14.09%	13.82%	13.19%
Net operating costs allocated to FBC (excluding cost of energy)	**$ 1,331**	**$ 1,724**	**$ 1,790**	**$ 1,659**
Net operating costs allocated to FBC using Massachusetts Formula (including cost of energy) per BCPSO 1.90.4.3	$ 1,218	$ 1,567	$ 1,661	$ 1,563
Increase in costs to FBC excluding cost of energy	$ 113	$ 157	$ 129	$ 96

While this question contemplates applying the Massachusetts formula to allocate the Fortis Inc. costs (Corporate Service fee), as described in Exhibit B-1, Section C4.17.3.1, on page 170 of FBC's 2014-2018 PBR Filing, the Fortis Inc. Corporate Service fees are "allocated to FBC using the assets by subsidiary driver which is a valid cost driver given the organizational structure of Fortis Inc. This allocation method was approved by the Commission in the 2012-2013 RRA Decision Order G-110-12. As mentioned above the Fortis Inc. cost pools and allocation methodology were reviewed by KPMG and found to be reasonable."

38.0 Reference: Exhibit B-1-6, October 18, 2013 Evidentiary Update page 269

38.1 On page 29, FBC indicates it is requesting approval of costs of the 2007 AMI regulatory process. Please provide an analysis of the costs to be recovered.

Response:

The table provided below details a breakdown of the costs associated with the 2007 AMI CPCN application.

Cost Category	**Amount ($000s)**
BCUC and Intervener Costs	34
Consulting Fees	42
Incremental Labour	130
Staff and Other Expenses	69
Total Expenditure	**275**
Income Tax Effect	(71)
Financing Costs	5
Net Expense	**209**

39.0 Reference: Exhibit B-1-6, October 18, 2013 Evidentiary Update page 272

39.1 Please fully explain why the costs of non-AMI meters are being amortized over five years.

<u>Response:</u>

The costs of the non-AMI meters are being amortized over five years, as that is the period of time approved by the BCUC.

Under Section *8.5.4 Accounting Treatment of the Existing Meters* on page 98 of Order C-7-13 dated July 23, 2013, which approved the AMI Project, the Commission Determination stated that [emphasis added]: "FortisBC is directed to record the cost of these meters in a rate base deferral account attracting FortisBC's weighted average cost of capital (WACC) as they are removed from service. Additions to the deferral account <u>are to be amortized over a period of five years</u>, commencing the year following their addition."